2004 ANNUAL REPORT TO SHAREHOLDERS

HIGH POINT RESOURCES INC.

EXECUTING OUR BUSINESS PLAN

corporate profile

High Point Resources Inc. is an oil and gas company engaged in the exploration for, and development and production of natural gas and light oil in Alberta and northeast British Columbia. The Corporation follows a strategy of assembling a land base in the west half of the Western Canada Sedimentary Basin that features high-quality, long-life natural gas reserves.

ANNUAL GROWTH

ANNUAL GENERAL MEETING

The Annual General Meeting of Shareholders of High Point Resources will be held on Wednesday, April 20, 2005 at 3:00 pm at the Calgary Petroleum Club, 319 – 5th Avenue SW, Calgary, Alberta. Shareholders are encouraged to attend and, if unable to do so, to sign and return the Instrument of Proxy at their earliest convenience.

TABLE OF CONTENTS

highlights

(unaudited)	Year ended December 31, 2004	2003	% Change	Three months ended December 31, 2004	2003	% Change
Production						
Light oil *(bbls/d)*	38	115	(67)	17	101	(83)
Heavy oil *(bbls/d)*	-	125	(100)	-	48	(100)
Natural gas *(mcf/d)*	15,166	10,133	50	15,037	13,533	11
Liquids *(bbls/d)*	443	193	130	549	344	60
Boe at 6:1 gas	3,009	2,121	42	3,072	2,749	12
Total boe produced	1,101,144	774,257	42	282,651	252,875	12
Prices						
Light oil *($/bbl)*	48.71	41.12	18	57.13	37.12	54
Heavy oil *($/bbl)*	-	25.76	-	-	17.76	-
Natural gas (pre hedge) *($/mcf)*	6.07	5.86	4	5.90	5.33	11
Natural gas (including hedge) *($/mcf)*	6.25	5.88	6	6.55	5.33	23
NGLs *($/bbl)*	39.28	32.61	20	45.40	31.69	43
$ per boe						
Gross revenues (net of hedges)	37.94	35.02	8	40.50	32.05	26
Royalties (net of ARTC)	(9.88)	(9.94)	(1)	(7.61)	(9.59)	(21)
Operating costs	(3.60)	(4.91)	(27)	(3.89)	(4.31)	(10)
Field net back	24.46	20.17	21	29.00	18.15	60
Other revenue	0.04	0.16	(75)	-	-	-
G&A	(2.42)	(3.13)	(23)	(2.02)	(3.06)	(34)
Interest	(1.71)	(1.31)	31	(1.59)	(1.76)	(10)
Taxes and other	(0.24)	(0.46)	(48)	(0.71)	(1.32)	(46)
Cash flow	20.13	15.43	30	24.68	12.01	105
***Financial** ($000s)*						
Gross revenues (net of hedges)	41,780	27,110	54	11,449	8,105	41
Royalties (net of ARTC)	(10,882)	(7,698)	41	(2,152)	(2,427)	(11)
Other income	45	124	(64)	1	1	-
Operating - cash expenses	(3,962)	(3,799)	4	(1,100)	(1,089)	1
G&A - cash expenses	(2,661)	(2,422)	10	(571)	(775)	(26)
Interest - cash expenses	(1,885)	(1,016)	86	(449)	(444)	1
Current taxes	(269)	(352)	(24)	(201)	(334)	(40)
Cash flow	22,166	11,947	86	6,977	3,037	130
D,D&A	(17,325)	(12,340)	40	(4,952)	(3,789)	31
Future tax (expense) recovery	(1,088)	2,180	(150)	(414)	1,241	(133)
Other - non cash expenses	(737)	(143)	415	(160)	(35)	357
Earnings (loss)	3,016	1,644	83	1,451	454	220
Net corporate debt	62,004	40,006	55	62,004	40,006	55
Weighted average outstanding shares	75,766,587	55,329,790	37	78,799,042	67,544,528	17
Cash flow per share (basic) *($)*	0.29	0.22	32	0.09	0.04	125
Earnings per share *($)*	0.04	0.03	33	0.02	0.01	100

president's message

A year ago, High Point accomplished the operating objectives in its strategic business plan. High Point became a low cost natural gas producer. Production, reserves and land were all associated with long-life gas reservoirs in the deeper portion of the Western Canada Sedimentary Basin. A multi-year gas development program and a drill-ready exploration program were in place.

ACHIEVEMENTS

In 2004, we expanded our presence in all core areas. Key operating achievements included:

- *Production growth of 42 percent.*
- *Proved producing reserves growth of 32 percent.*
- *Reserve life index of 8.3 years proved, 10.5 years proved plus probable .*
- *Proved producing reserves replaced production by 2.7 times.*
- *Proved and probable reserves increased by 14 percent.*
- *Undeveloped land increased by 32 percent.*
- *Unit operating costs were reduced by 27 percent to $3.60 per boe.*

The expanded and improved asset base resulted in a:

- *Thirty-two percent increase in cash flow per share.*
- *Thirty-three percent increase in earnings per share.*
- *Fifteen percent increase in net asset value per share.*
- *Twenty-five percent reduction in year-end debt to cash flow.*

The 2004 achievements were a result of organic growth. High Point made no corporate or production acquisitions in 2004 and divested several non-core assets.

CAPITAL ACTIVITIES

High Point invested $63.2 million in 2004; 62 percent on drilling and completions, 22 percent on facilities and pipelines and 15 percent on land and seismic. The capital investment increased proved producing reserves by 2.9 million boes; proved and probable reserves by 2.6 million boes and undeveloped land by 26,000 net acres. Excluding the capital for land and seismic, which are related to future projects, proved producing reserves were added at a cost of $16.50 per boe. The capital program was funded by $22 in cash flow, $5 million in asset sales, $14 million in equity and a $22 million increase in net debt.

High Point has a drilling inventory of over 160 development locations in its three core operating areas of Desan/Peggo, Ferrier and Ricinus. High Point operates all of its major developments with a corporate average working interest of 75 percent. In the next three years, the company plans to drill approximately 60 wells or 40 percent of the current drilling inventory. The expansion of our land holdings at Ferrier and the emergence of Ricinus as a strong development property allow a better balance between winter and summer capital programs in the future. In 2005, High Point will evaluate the best alternatives to monetize the excess drilling inventory which is not required to meet our three year growth plan.

High Point has been assembling land in the Ricinus area of west central Alberta since 2002. Forty-three sections of land have been acquired in the Ricinus area with an average working interest of 67 percent. Ricinus commenced production in April, 2004 and gas processing facilities were expanded in October, 2004. The field is currently producing over 450 boe per day from five wells. Two additional development wells at Ricinus are planned for the first quarter of 2005. Ricinus will be a focal point of operations in 2005 and beyond.

president's message

In addition to the development program, success on any of the company's exploration prospects would have a material effect on the value of the company. Desan, Ricinus and Lochend are all projects that were derived from grass roots exploration in High Point's three year history. The exploration prospects are drill-ready. Wells are licensed at Kotcho and Ricinus, while locations are being selected on our Mackenzie prospect. Three dimensional seismic has also identified deeper targets underlying our Ferrier development lands.

High Point attempted to drill its Kotcho Keg River reef prospect in the fall of 2004. The well experienced mechanical problems and had to be junked and abandoned prior to penetrating the Keg River formation. A new well is licensed on the same location and was slated for drilling in March of this year. Unseasonably warm weather is occurring in northeast British Columbia, resulting in a deferral of the Kotcho re-drill until after spring break-up. High Point plans to drill an exploratory gas well at Ricinus targeting the Leduc reef complex as a substitute for the Kotcho well. The Ricinus well site is currently being built with a drilling rig contracted for April, 2005.

FINANCIAL RESOURCES

The goal when we established High Point was to have sustainable and profitable growth. Our plan is to accomplish this growth through re-investment of cash flow and increased bank facilities. The quality and long-life nature of High Point's asset base allows us to maintain higher debt levels than most junior oil and gas companies, maximizing leverage for our shareholders. The cost of debt in 2004 was 4.4 percent. High Point also maintains an active hedging policy to ensure sufficient cash flow to execute the capital program and service the debt.

OUTLOOK

High Point will continue with its organic growth strategy in 2005. Internal estimates indicate that the first quarter 2005 drilling program has increased the proved producing reserves and average 2005 production by approximately 20 percent over levels achieved in 2004. By relying solely on its drilling program to fuel growth, High Point will continue to experience "choppy" quarterly growth; however annual growth will remain strong.

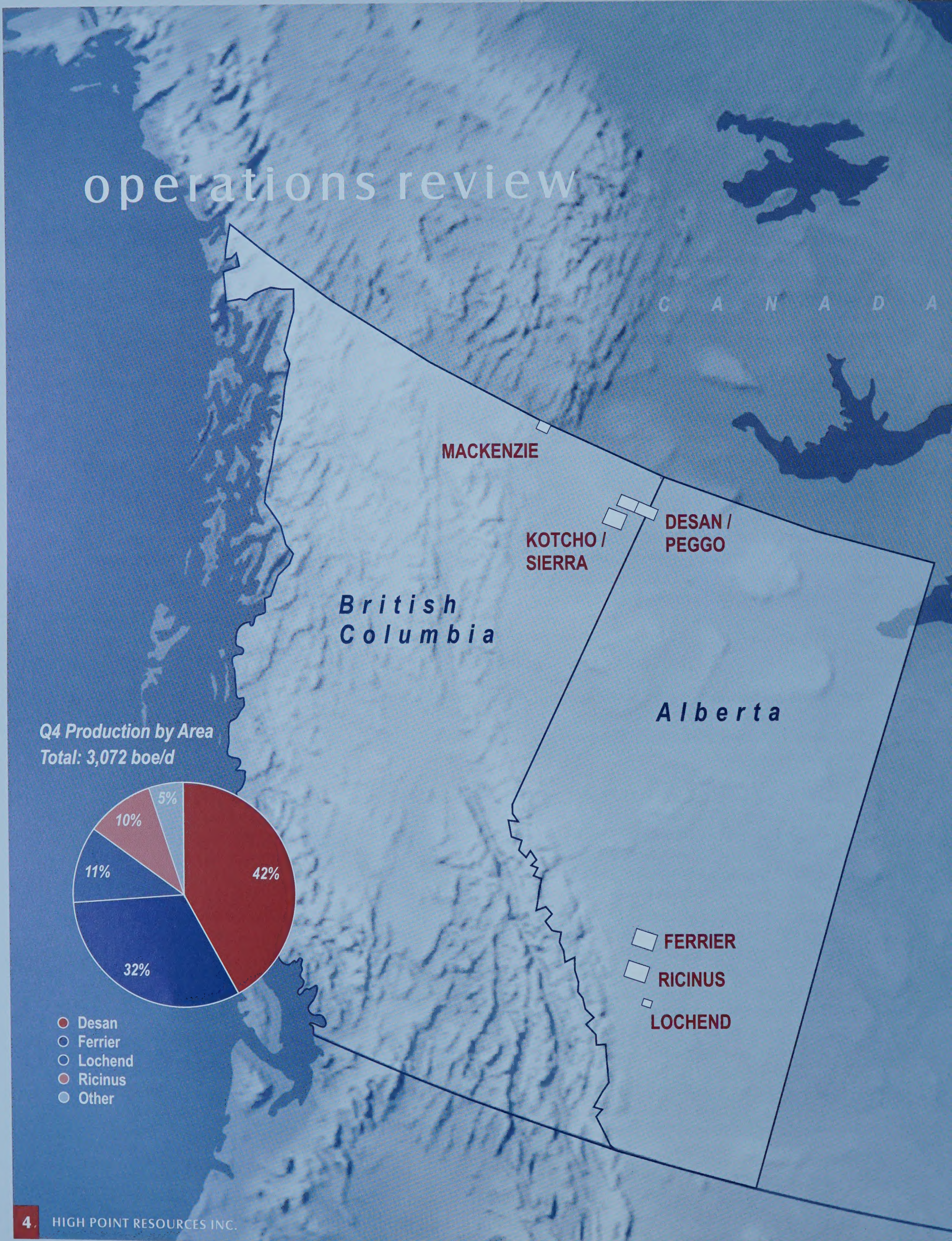
The strength in commodity prices in both the short and long term is resulting in an extremely competitive market for production, prospects and services. In the areas where High Point operates, land value has increased fourfold in the last two years. Having established our land and prospect inventory early in the current cycle, High Point has significant advantages over a number of its competitors. A large drilling and prospect inventory, combined with a low operating cost structure positions High Point to take advantage of strong commodity prices, while remaining profitable when prices retreat.

As the company production base expands, organic production growth of 25 to 30 percent is achievable from the development program, in the current commodity price environment. Success at any one of our high impact exploration wells would result in a step rate increase to the annual production and reserve growth of the company.

On behalf of the management and staff of High Point, I would like to thank the shareholders and directors for their continued support.

Glen A. Yeryk
President and CEO

operations review



BRITISH COLUMBIA

Desan / Greater Sierra

High Point holds a 100 per cent interest in 97 sections of land in the Greater Sierra area of northeast British Columbia. The main target in this area is natural gas in the Devonian Jean Marie formation, which is a regional limestone at a depth of approximately 1,300 metres. This area is being developed using underbalanced horizontal drilling technology, with one well drilled per section. The greater Sierra area is mainly a winter access area, with most activity occurring from December through March.

At Desan, High Point holds 54 sections of land, with 17 Jean Marie wells on production at year-end. High Point is currently completing its third winter drilling program in the area, with six wells targeted to be drilled and on production early in April, 2005. High Point has identified another 32 drilling locations on lands in this area, representing a three to four year inventory of drilling locations.

In mid-2004, High Point acquired 24 sections of undeveloped land in the Peggo area, east of Desan, within three miles of the Alberta border. These lands replenish the inventory of undeveloped land in this area and High Point's 2005 winter seismic program has identified a number of drillable locations on these lands for the winter drilling season of 2005/2006.

At Kotcho, High Point holds 19 sections of undeveloped land on which two independent Keg River/Pine Point prospects have been identified. The first exploratory well drilled in this area encountered technical problems and had to be scrapped without reaching the target Keg River zone. A replacement well will be drilled in mid-2005, adjacent to the original well. In addition to the Keg River/Pine Point prospect, High Point has nine drillable locations for Jean Marie gas.

Mackenzie

MacKenzie is a major exploration prospect in the early stages of evaluation. High Point holds a 100 percent interest in selective rights on 38 sections of land at MacKenzie, in northeast British Columbia. Pipeline infrastructure is already in place from an earlier development of deep horizons in the area. While deep targets include the Nahanni and Slave Point formations, High Point is focused on the shallower targets in the Banff, Matson and Jean Marie zones. A three dimensional seismic program was acquired in January, 2004 and locations are being selected for a drilling program expected to commence in late 2005 or early 2006.

ALBERTA

Ferrier

High Point holds an average 40 percent interest in 51 sections of land in the Ferrier area of western Alberta. A total of 62 wells (12 net) have been drilled in this area, targeting liquids-rich natural gas in the Rock Creek, Ellerslie and Ostracod zones at depths of up to 2,900 metres. With the current spacing of two wells per section, High Point has identified 24 future drilling locations, eight to ten of which will be drilled in 2005.

In 2004, High Point acquired a 100 percent working interest in an additional 9.5 sections of land at Ferrier. A seismic program shot in December, 2004 has identified a number of development locations on these lands, as well as two deeper exploration targets.

Ricinus

High Point has assembled 43 sections of land with an average working interest of 67 percent in this exploratory area south of Ferrier. Targeting liquids-rich gas and light oil in the Cardium formation, High Point has drilled five wells, with another eight to ten locations identified. Seismic interpretation is in progress to evaluate potential in the deeper horizons on new lands acquired on the west side of the area.

The Ricinus area was High Point's largest production growth area in 2004. Production commenced in April, 2004 at 10 boe per day and is currently producing 450 boe per day.

Lochend

Lochend is a relatively mature area producing light oil and natural gas from Cardium bar trends. A total of 24 wells are producing and five to seven more wells are planned over the next two years. High Point's working interest at Lochend is 21 percent.

management's discussion and analysis

Management's Discussion & Analysis ("MD&A") of financial results and operations is presented by management of High Point Resources Inc. ("High Point" or the "Corporation") to review financial results and operating activities for the three and twelve month periods ended December 31, 2004, and the three and twelve month periods ended December 31, 2003. The MD&A has been prepared in accordance with Canadian generally accepted accounting principles ('GAAP'). This MD&A is based on information available as of March 9, 2005.

This MD&A contains forward-looking statements, including forecasted future production, cash flow and earnings. These statements are based on management's current expectations, which involve a number of risks and uncertainties which could cause actual results to differ materially from those projected in the MD&A. These risks include competition and operational risks relating to exploration and development activities; fluctuating commodity prices and exchange rates; uncertainty in estimates of reserves, production and costs; and legislative, environmental and other regulatory or political changes. Accordingly, there is no assurance that the forward-looking statements will prove to be correct and High Point assumes no obligation to publicly update or revise any forward-looking statements.

Natural gas reserves and volumes are converted to barrels of oil equivalent (boe) on the basis of six thousand cubic feet (mcf) of gas to one barrel (bbl) of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

All references to dollar values refer to Canadian dollars, unless otherwise stated.

Additional information relating to the Corporation, including the Annual Information Form, can be found on the SEDAR website at www.sedar.com.

NON-GAAP MEASUREMENTS

The MD&A uses the terms "cash flow from operations" and "cash flow", which should not be considered an alternative to, or more meaningful than, cash flow from operating activities or net earnings as determined in accordance with Canadian GAAP as an indicator of High Point's performance. High Point's determination of cash flow from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and cash flow from operations can be found in the Consolidated Statements of Cash Flows. The Corporation also presents "cash flow per share", whereby cash flow from operations is divided by the weighted average number of shares outstanding to determine per share amounts.

High Point uses the term net debt in its MD&A and presents a table showing how it has been determined. This measure does not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other companies.

High Point uses these non-GAAP measures to assist readers in understanding High Point's overall financial position and in comparing High Point's results to industry averages.

CORPORATE VISION AND STRATEGY

High Point is an oil and gas company engaged in the exploration for, and development and production of natural gas and light oil in Alberta and northeast British Columbia. The Corporation follows a strategy of assembling a land base in the west half of the Western Canada Sedimentary Basin that features high-quality, long-life natural gas reserves. While the oil and gas industry is subject to fluctuating product prices, we are of the view that North American gas prices will remain strong because of a scarcity of supply and increasing demand. High Point focuses on properties with sustainable natural gas development and high impact natural gas exploration. The Corporation has a very focused land base in west central Alberta and northeast British Columbia, comprised of five core areas which offer multi-year exploration and development potential near gas infrastructure. High Point's strong internal prospect generation may be supplemented by strategic acquisitions to provide continuing growth.

management's discussion and analysis

PRODUCTION

	Year ended December 31, 2004				2003			
	Natural gas (mcf/d)	Oil (bbls/d)	NGL (bbls/d)	Boe (boe/d)	Natural gas (mcf/d)	Oil (bbls/d)	NGL (bbls/d)	Boe (boe/d)
Desan	**8,722**	**-**	**44**	**1,498**	6,545	-	38	1,128
Ferrier	**3,404**	**1**	**191**	**759**	1,196	3	66	268
Lochend	**1,535**	**37**	**162**	**455**	575	45	61	202
Medicine Lodge	**602**	**-**	**8**	**108**	1,248	-	20	228
Alexander/Newton (sold)	**381**	**-**	**1**	**65**	179	-	-	30
Ricinus	**452**	**-**	**37**	**112**	12	-	1	3
Lloydminster (sold)	**-**	**-**	**-**	**-**	-	125	-	125
Progress (sold)	**-**	**-**	**-**	**-**	44	61	-	68
Other	**70**	**-**	**-**	**12**	334	6	7	69
Daily average	**15,166**	**38**	**443**	**3,009**	10,133	240	193	2,121

	Three months December 31, 2004				2003			
	Natural gas (mcf/d)	Oil (bbls/d)	NGL (bbls/d)	Boe (boe/d)	Natural gas (mcf/d)	Oil (bbls/d)	NGL (bbls/d)	Boe (boe/d)
Desan	**7,593**	**-**	**38**	**1,303**	8,281	-	48	1,428
Ferrier	**4,338**	**2**	**269**	**994**	2,598	5	151	589
Lochend	**1,193**	**18**	**133**	**350**	1,105	51	116	351
Medicine Lodge	**541**	**-**	**8**	**98**	909	-	13	165
Alexander/Newton (sold)	**232**	**-**	**1**	**40**	402	-	1	68
Ricinus	**1,243**	**-**	**99**	**306**	-	-	-	-
Lloydminster (sold)	**-**	**-**	**-**	**-**	-	48	-	48
Progress (sold)	**-**	**-**	**-**	**-**	43	42	-	49
Other	**(103)**	**(3)**	**1**	**(19)**	195	3	15	51
Daily average	**15,037**	**17**	**549**	**3,072**	13,533	149	344	2,749

Production from the Ricinus area began late in 2004, resulting in average production of only 112 boe per day for 2004. Current production from the Ricinus area is more than 450 boe per day.

PRODUCT MIX

High Point's product mix averaged 99 percent natural gas and natural gas liquids during 2004.

	Year ended December 31, 2004		2003		Three months ended December 31, 2004		2003	
Natural gas *(mcf/d)*	**15,166**	84%	10,133	80%	**15,037**	82%	13,533	82%
NGLs *(bbls/d)*	**443**	15%	193	9%	**549**	18%	344	13%
Oil *(bbls/d)*	**38**	1%	240	11%	**17**	0%	149	5%
Boe/d *(6:1)*	**3,009**	100%	2,121	100%	**3,072**	100%	2,749	100%

management's discussion and analysis

Average production for 2004 was 3,009 boe per day, up 42 percent from 2,121 boe per day in 2003, reflecting growth from the successful drilling programs at Ferrier, Ricinus, Lochend and Desan. Desan and Ferrier accounted for 75 percent of total production in 2004. Daily production of 3,072 boe per day in the fourth quarter was up three percent from 2,978 boe per day in the third quarter, as some of the wells drilled at Ferrier and Ricinus in the summer were tied in. Six of the wells drilled at Ferrier and Ricinus were not tied in until the first quarter of 2005, as availability of services in the industry continues to be an issue.

COMMODITY PRICING AND MARKETING

	Year ended December 31,		*Three months ended December 31,*	
High Point average prices	*2004*	*2003*	*2004*	*2003*
Light oil *($/bbl)*	**48.71**	41.12	**57.13**	37.12
Heavy oil *($/bbl)*	**-**	25.76	**-**	17.76
Natural gas *($/mcf)*	**6.07**	5.86	**5.90**	5.33
Hedging impact *($/mcf)*	**0.18**	0.02	**0.65**	-
Net gas *($/mcf)*	**6.25**	5.88	**6.55**	5.33
Natural gas liquids *($/bbl)*	**39.28**	32.61	**45.40**	31.69

Petroleum products are sold to major Canadian marketers at spot reference prices based on USD WTI for crude oil and AECO-C for natural gas. The average wellhead price of natural gas increased three percent from $5.86/mcf in 2003 to $6.07/mcf ($6.25 after hedging) in 2004. Fourth quarter 2004 gas pricing was $5.90/mcf ($6.55 after hedging), compared to $5.83 ($5.85 after hedging) in the third quarter and $5.33 in the fourth quarter of 2003.

COMMODITY RISK MANAGEMENT

High Point enters into hedging transactions to protect our cash flows and enhance our ability to carry out our planned capital expenditure program. Hedging contracts outstanding in December, 2004 covered one-half of December gas sales and result in prices on that portion of High Point's sales being fixed at those price levels. The hedging of gas sales in 2004 contributed $1,032,306 to gas revenues.

The following is a summary of all hedging activities affecting 2004 and 2005:

Period	*Volume hedged*	*AECO price*
Feb. 1, 2003 - Jan. 31, 2004	2,000 GJ/day (1.9 mmcf/d)	$5.50/GJ ($5.80/mcf) to $7.54/GJ ($7.86/mcf)
Mar. 1, 2003 - Feb. 29, 2004	2,000 GJ/day (1.9 mmcf/d)	$5.50/GJ ($5.80/mcf) to $7.47/GJ ($7.88/mcf)
Jan. 1, 2004 - Mar. 31, 2004	4,000 GJ/day (3.8 mmcf/d)	$7.21/GJ ($7.61mcf)
Feb. 1, 2004 - Oct. 31, 2004	2,000 GJ/day (1.9 mmcf/d)	$6.04/GJ ($6.36/mcf)
Apr. 1, 2004 - Oct. 31, 2004	4,000 GJ/day (3.8 mmcf/d)	$5.89/GJ ($6.20/mcf)
Nov. 1, 2004 - Mar. 31, 2005	3,000 GJ/day (2.9 mmcf/d)	$7.90/GJ ($8.32/mcf)
Nov. 1, 2004 - Mar. 31, 2005	3,000 GJ/day (2.9 mmcf/d)	$8.01/GJ ($8.41/mcf)
Nov. 1, 2004 - Mar. 31, 2005	2,000 GJ/day (1.9 mmcf/d)	$8.58/GJ ($9.01/mcf)
Apr. 1, 2005 - Oct. 31, 2005	6,000 GJ/day (5.7 mmcf/d)	$6.95/GJ ($7.30/mcf)
Apr. 1, 2005 - Oct. 31, 2005	3,000 GJ/day (2.9 mmcf/d)	$6.82/GJ ($7.16/mcf)

management's discussion and analysis

The CICA issued Accounting Guideline 13 "Hedging Relationships", effective for fiscal years beginning on or after July 1, 2003. The Guideline addresses the type of contracts that qualify for hedge accounting and the requirement to evaluate hedges for effectiveness. High Point has adopted hedge accounting for all its hedging contracts, as physical sales contracts are entered into at the same time and on identical terms as the hedge contracts. As a result, the Corporation has a perfect relationship between the hedge contract and the underlying physical sale. The adoption of the new Guideline had no effect on High Point's Consolidated Financial Statements. As of December 31, 2004, the outstanding hedge contracts had an unrealized positive value of $958,980. Credit risks associated with hedging contracts are obviated by restricting transactions to financially strong counterparties.

PETROLEUM AND NATURAL GAS - GROSS REVENUES

	Year ended December 31,				*Three months ended December 31,*			
	2004		*2003*		*2004*		*2003*	
	($000s)	*(%)*	*($000s)*	*(%)*	*($000s)*	*(%)*	*($000s)*	*(%)*
Natural gas	**35,998**	84	23,356	82	**8,852**	79	7,138	84
NGLs	**6,372**	15	2,295	8	**2,292**	20	1,003	10
Oil	**673**	1	2,895	10	**90**	1	423	6
Royalty revenue	**37**	-	159		**5**	-	42	
Subtotal	**43,080**	100	28,705	100	**11,239**	100	8,606	100
Transportation	**(2,332)**		(1,650)		**(689)**		(503)	
Hedging gain	**1,032**		55		**899**		2	
Total revenue	**41,780**		27,110		**11,449**		8,105	

In 2004, 99 percent of High Point's revenues came from sales of natural gas and associated liquids, up from 84 percent in 2003. Gross revenues in 2004 were $41.8 million, up 54 percent from $27.1 million for 2003. The revenue increase resulted from a 42 percent increase in daily production volumes, combined with increased commodity prices and hedging gains.

Gross revenues of $11.4 million in the fourth quarter were up from $9.9 million in the third quarter, reflecting a three percent increase in production volumes between quarters and a $0.70/mcf increase in gas prices received, largely due to High point's hedging program.

ROYALTIES

	Year ended December 31,		*Three months ended December 31,*	
($000s)	*2004*	*2003*	*2004*	*2003*
Crown	**8,740**	6,185	**1,603**	1,986
Other	**2,770**	1,979	**585**	524
ARTC and GCA	**(628)**	(466)	**(36)**	(83)
Total	**10,882**	7,698	**2,152**	2,427

ROYALTIES AS A PERCENTAGE OF SALES

(%)	*Desan*	*Ferrier*	*Lochend*	*Medicine Lodge*	*Ricinus*	*Average*
Crown	26	21	9	29	0	21
GORR	12	2	10	3	2	7
Total royalties	38	23	19	32	2	28

management's discussion and analysis

In 2004, royalties net of ARTC and gas cost allowance credits were $9.88/boe, compared to $9.94/boe in 2003. Royalty rates dropped with the payout of the bridge financing facility, which had a five percent gross overriding royalty attached to specific projects in the Desan area. With the repayment of the loan facility in July 2004, the gross overriding royalty dropped from five to 1.6 percent. High Point purchased the remaining 1.6 percent gross overriding royalty effective January 1, 2005 for $590,000.

Crown royalty rates were also down from the 23 percent average in 2003 because of deep well royalty credits earned by drilling at Ferrier and Ricinus. Amounts received in 2004 for gas cost allowance credits and Alberta royalty tax credits were up 35 percent over 2003.

OPERATING EXPENSES

Operating expenses were $3.60/boe for 2004, down 27 percent from the $4.91/boe for the same period in 2003. This decrease reflects the sale of higher cost oil properties in the second half of 2003 and increased production from lower cost gas properties. Operating costs in the fourth quarter of 2004 were $3.89/boe, down 10 percent from $4.31/boe in the fourth quarter of 2003.

High Point's focused land base, operating control of its gas properties and ownership of key in-field facilities and pipelines will ensure that operating costs remain top quartile in 2005.

GENERAL AND ADMINISTRATION COSTS

	Year ended December 31,				*Three months ended December 31,*			
	2004		*2003*		*2004*		*2003*	
	($000s)	*($/boe)*	*($000s)*	*($/boe)*	*($000s)*	*($/boe)*	*($000s)*	*($/boe)*
Gross	**3,640**	**3.31**	3,122	4.03	**901**	**3.19**	1,043	4.12
Recoveries	**(979)**	**(0.89)**	(700)	(0.90)	**(330)**	**(1.17)**	(268)	(1.06)
Total	**2,661**	**2.42**	2,422	3.13	**571**	**2.02**	775	3.06

While total general and administration expenses were 10 percent higher in 2004, per boe G&A costs declined 23 percent from 2003 as production levels increased. Personnel and consulting costs increased 23 percent with the growth in the Corporation, while office rent and expenses increased 41 percent, as the Corporation's office lease was renewed at a higher rate in the second quarter of 2003. At December 31, 2004, High Point had 17 employees and seven part-time consultants.

General and administration ("G&A") expenses in the three month period ended December 31, 2004 were 26 percent lower than the same three month period ended December 31, 2003. This reflects increased overhead recoveries from higher capital expenditures in 2004, and 'one time' expenses in December 2003 related to the move to the TSX exchange from the TSX Venture exchange.

INTEREST

Interest expense incurred under the bank credit facility was $1,289,506 in 2004 compared with $713,931 for 2003, reflecting increased drawings since March 31, 2003. At December 31, 2004, $50 million had been drawn against the credit facility compared with $20 million drawn against the credit facility and $10 million drawn under a bridge financing facility, at December 31, 2003. Fourth quarter bank interest was $449,326 in 2004, compared with $299,298 of bank interest for the fourth quarter of 2003, due to higher debt levels in 2004.

Other cash interest paid in 2004 was $595,804, which included $48,818 on the convertible debentures, and $546,986 on the bridge financing facility. $15 million was drawn against the bridge facility throughout the greater portion of the first half of 2004 until it was repaid in July, 2004. Fourth quarter other interest was nil in 2004 and $145,398 in 2003.

For 2004, the effective interest rate was 4.4 percent (4.7 percent for 2003).

management's discussion and analysis

CURRENT TAXES

The current tax expense of $268,787 includes 2004 Large Corporations Tax ("LCT") instalments of $189,442 offset by a credit of $82,671 for 2003, representing assessed LCT that was lower than had been accrued in 2003. Also included is $162,016 for Part XII.6 tax related to the timing of flow through share expenditures in 2004.

CASH FLOW

Increased production levels and improved prices led to cash flow for 2004 of $22,165,572 or $0.29 per share, compared to $11,947,386 or $0.22 per share for the same period in 2003, an increase of 86 percent.

NETBACKS

Operating netbacks increased 21 percent in 2004, which reflects a six percent increase in selling prices, complemented by hedging gains and a 27 percent reduction in per unit operating costs.

	Year ended December 31, 2004		2003		
	($000s)	($/boe)	($000s)	($/boe)	($/boe - % change)
Gross revenue	**40,748**	**37.01**	27,056	34.95	6
Hedges	**1,032**	**0.93**	55	0.07	1,228
Royalties	**(11,510)**	**(10.45)**	(8,165)	(10.54)	(1)
ARTC and GCA	**628**	**0.57**	466	0.60	(5)
Subtotal	**30,898**	**28.06**	19,412	25.08	12
Operating costs (cash)	**(3,962)**	**(3.60)**	(3,799)	(4.91)	(27)
Operating netback	**26,936**	**24.46**	15,613	20.17	21
Other	**45**	**0.04**	124	0.16	(75)
Administration costs (cash)	**(2,661)**	**(2.42)**	(2,422)	(3.13)	(23)
Interest costs	**(1,885)**	**(1.71)**	(1,016)	(1.31)	(30)
Taxes and other	**(269)**	**(0.24)**	(352)	(0.46)	(48)
Cash flow from operations	**22,166**	**20.13**	11,947	15.43	30

	Three months ended December 31, 2004		2003		
	($000s)	($/boe)	($000s)	($/boe)	($/boe - % change)
Gross revenue	**10,550**	**37.33**	8,103	32.04	17
Hedges	**899**	**3.17**	2	0.01	3,160
Royalties	**(2,188)**	**(7.74)**	(2,411)	(9.53)	(19)
ARTC and GCA	**36**	**0.13**	(16)	(0.06)	317
Subtotal	**9,297**	**32.89**	5,678	22.46	46
Operating costs (cash)	**(1,100)**	**(3.89)**	(1,089)	(4.31)	(10)
Operating netback	**8,197**	**29.00**	4,589	18.15	60
Other	**1**		1	-	-
Administration costs (cash)	**(571)**	**(2.02)**	(775)	(3.06)	(34)
Interest costs	**(449)**	**(1.59)**	(444)	(1.76)	(10)
Taxes and other	**(201)**	**(0.71)**	(334)	(1.32)	(46)
Cash flow from operations	**6,977**	**24.68**	3,037	12.01	105

management's discussion and analysis

NETBACKS PER BOE AND CASH FLOW FROM OPERATIONS, BY PROPERTY

	Desan	*Ferrier*	*Lochend*	*Medicine Lodge*	*Alexander/Newton*	*Ricinus*
Revenue	33.58	43.31	35.99	40.39	40.94	43.31
Royalties	(12.89)	(9.79)	(6.88)	(12.82)	(8.41)	(0.92)
Operating costs	(3.09)	(3.97)	(3.85)	(2.28)	(4.51)	(9.21)
Field netback	17.60	29.55	25.26	25.29	28.02	33.18
Cash flow *($000s)*	9,650	8,207	4,202	997	663	1,365
Cash flow *(%)*	38	33	17	4	3	5

Netbacks and cash flow at the property level do not include ARTC and corporate hedging.

The netbacks at Desan will improve in 2005 as new wells are drilled on non-GORR lands and per unit third party transportation costs are reduced.

DEPLETION AND DEPRECIATION

Total depletion and depreciation for the year ended December 31, 2004 was $17.3 million compared to $12.3 million in 2003. The amounts were higher in 2004 because of the much larger property and equipment carrying value and higher production. Depletion and depreciation rates for oil and gas properties were $15.68/boe for 2004, down slightly from $15.76 in 2003. A ceiling test was performed as at December 31, 2004, resulting in an excess of fair market value over net book value of depletable assets of $24 million.

Depletion and depreciation was $4.9 million for the fourth quarter of 2004, compared to $3.8 million in 2003. Depletion and depreciation rates for oil and gas properties were $17.46/boe for the fourth quarter of 2004, compared to $14.84/boe in 2003.

In January, 2004, High Point adopted a new accounting standard relating to asset retirement obligations ("ARO"). For the fourth quarter and year ended 2004 respectively, accretion expense of $33,031 and $111,949 relating to the ARO was recorded. This compares to $17,356 and $69,422 recorded for 2003 on a restated basis.

STOCK-BASED COMPENSATION

Stock-based compensation expense of $127,445 was recorded for the fourth quarter and $604,294 was recorded for 2004, pursuant to the new accounting standard adopted January 1, 2004. There were no amounts recorded in 2003.

FUTURE TAXES

A future tax provision of $1,088,223 was recorded in 2004. The provision includes a $1 million recovery mainly relating to recognition of an Alberta provincial tax rate reduction. Given current capital spending levels, High Point does not expect to be taxable until 2006 or later.

Future income tax liability	*($000s)*
Balance at December 31, 2003	29,836
Flow through share renouncement in 2004	50
Tax effect of share issue costs	(343)
Provision for 2004	1,088
Balance at December 31, 2004	30,631

management's discussion and analysis

In 2003, High Point issued $16 million in flow-through shares and had renounced the tax benefit of $16 million to the shareholders. Pursuant to the 'look back' provisions governing flow-through shares, the Corporation was required to spend the $16 million in exploratory capital expenditures in 2004. As of December 31, 2004, the Corporation had fulfilled its obligation.

In 2004, the Corporation issued $7.5 million in flow-through shares and has renounced the tax benefit to the shareholders. By December 31, 2004, the Corporation had spent $6.3 million in eligible capital expenditures, leaving $1.2 million to be spent by December 31, 2005 under the 'look back' provision. These amounts were spent early in 2005.

EARNINGS

The increased production and cash flow led to earnings of $3,015,676 or $0.04 per share, compared to $1,644,101 or $0.03 per share in 2003. Net earnings in the fourth quarter of 2004 were $1,451,298 or $0.02 per share, compared to $453,246 or $0.01 per share in 2003. The results for 2003 have been restated due to the retroactive adoption of the new asset retirement obligation standard.

CAPITAL EXPENDITURES

Capital expenditures were $63.2 million in 2004, compared to $52.0 million in 2003. The 2004 expenditures include approximately $1.5 million in pipe purchases related to first quarter 2005 drilling. A total of 41 wells (21.5 net) were drilled in 2004 or in progress at December 31, 2004, with a 98 percent success rate.

Fourth quarter capital expenditures in 2004 were $19.1 million, compared to $12.5 million in the third quarter and $14.4 million in the fourth quarter of 2003. A total of 10 wells (net 5.75) were drilled, or were drilling, in the fourth quarter of 2004.

	Year ended December 31,		*Three months ended December 31,*	
($000s)	*2004*	*2003*	*2004*	*2003*
Land	**6,495**	2,712	**1,896**	66
Geological and geophysical	**3,437**	1,211	**1,449**	49
Drilling, completions and abandonments	**39,431**	37,944	**13,063**	12,056
Plant and facilities	**13,552**	9,948	**2,630**	2,696
Other assets	**284**	214	**60**	21
Total capital expenditures	**63,199**	52,029	**19,098**	14,888

EXPENDITURES BY AREA

For the year ended December 31, 2004	*Land*	*Geological and geophysical*	*Drilling completions and abandons*	*Plant and facilities*	*Other*	*Total*
($ 000s)						
Desan	-	1,103	16,036	7,286	-	24,425
Lochend	7	-	1,444	622	-	2,073
Ricinus	802	616	8,066	1,868	-	11,352
Ferrier	2,584	1,117	10,906	2,105	-	16,712
Kotcho-Sierra	66	148	1,841	-	-	2,055
Mackenzie	-	390	-	-	-	390
Other	3,036	63	1,138	1,671	284	6,192
Total	6,495	3,437	39,431	13,552	284	63,199

management's discussion and analysis

Effective January 28, 2004 the Corporation sold its gas producing properties at Wembley, Alberta for proceeds of $1.1 million. Effective November 1, 2004 the Corporation sold its gas producing properties at Alexander and Newton for proceeds of $3.5 million.

WELLS DRILLED

	Drilled and producing		*Drilled and standing*		*Work in progress*	
	Gross	***Net***	***Gross***	***Net***	***Gross***	***Net***
Desan	3	3.00	4	4.00	2	2.00
Lochend	4	0.84	2	0.42	1	0.21
Ferrier	8	3.01	-	-	8	3.32
Ricinus	3	2.76	-	-	1	0.75
Kotcho	-	-	1	0.45	-	-
Other	4	0.71	-	-	-	-
Total	22	10.32	7	4.87	12	6.28

A total of $6.5 million was spent in 2004 on land acquisition, with $2.6 million spent to acquire 24 sections of land at Peggo/Pesh in northeast British Columbia and $2.5 million to acquire nine and one-half sections at Ferrier, all at a 100 percent working interest. The acquisition of these lands perpetuates High Point's three year inventory of in-house exploration and development projects.

The winter drilling program at Desan saw seven gas wells drilled in the first quarter of 2004, with three tied in and on production, and four requiring further testing next winter. A total of 16 Desan wells were on production during 2004. In December 2004, two new wells were spud at Desan and were drilling at December 31, 2004. The wells are part of the 2005 winter drilling program of six to eight wells, which will be completed by March 31, 2005.

At Lochend, seven oil/gas wells were drilled, with four put on production and one currently being tied in, while two others are awaiting further evaluation.

At Ferrier, 16 gas wells were drilled with eight on production and eight being completed and tied in during the first quarter of 2005. Wet fall conditions and difficulty in procuring field services delayed the tie-in of these wells.

Three exploratory gas wells at Ricinus were drilled, tied in and on production at December 31, 2004, with a fourth well being tied in and on production in January 2005.

Plant and facilities expenditures of $13.6 million reflect the construction of compression facilities and associated pipelines in 2004 at Desan, Ferrier and Ricinus. Ownership of these facilities improves operational control and keeps operating costs low.

SHARES OUTSTANDING

At December 31, 2004, 79,386,196 common shares were outstanding. At the date of this report, there are 79,446,197 common shares outstanding and 5,297,333 stock options outstanding to employees, consultants, officers and directors, with an average exercise price of $1.51 per share. All options are granted for a maximum term of five years and vest one-third upon issue, one-third after one year, and one-third after two years.

management's discussion and analysis

DEBT AND WORKING CAPITAL

At year-end, High Point had a $12.0 million working capital deficiency and had drawn $50 million on its $60 million bank credit facility.

	Year ended December 31,	
($000s)	2004	2003
Cash and working capital (deficiency)	(12,004)	(10,006)
Bank debt	(50,000)	(20,000)
Bridge financing	-	(10,000)
Net debt	(62,004)	(40,006)

Source of funds used in 2004	($000s)
Net proceeds from disposal of properties	4,601
Decrease in bridge financing	(10,000)
Increase in bank financing	30,000
Issuance of shares, net of costs	14,175
Funds provided by operations	22,166
Change in cash and working capital	1,998
Other	259
	63,199
Additions to property and equipment	63,199

LIQUIDITY AND CAPITAL RESOURCES

The $63.2 million capital expenditure program in 2004 was funded by cash flow from operations of $22.2 million, an equity issue of $14.2 million net of issue costs, $4.6 million of proceeds from asset sales, and an increase of $22.0 million in net debt. On May 11, 2004, the Corporation issued 3,870,000 common shares at $1.95 per share and 3,000,000 flow-through shares at $2.50 per share for total proceeds of $15,046,000. Costs of $870,479 were recorded in relation to the issue.

On July 21, 2004, the bank credit facility was increased from $32 million to $52 million and the $15 million bridge financing facility was repaid. The repayment consolidated the Corporation's debt and lowered overall interest costs. The $52 million bank credit facility was increased to $60 million on December 17, 2004. On December 2, 2004 a $15 million standby bridge financing facility was signed and may be drawn anytime up to March 31, 2005. The Corporation's cash flow and credit facilities are sufficient to fund the planned capital expenditures program for 2005.

management's discussion and analysis

RESERVES

High Point retained the independent engineering firm of Gilbert Laustsen Jung Associates Ltd. ("GLJ") to evaluate the Corporation's reserve properties at December 31, 2004.

Reserves reconciliation

	Crude oil and liquids			Natural gas			Barrel equivalent (6:1)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
		(mbbl)			(bcf)			(mmbbl)	
Total at December 31, 2003	1,338.7	386.8	1,725.5	41.3	8.78	50.08	8.22	1.85	10.07
Development	665.5	335.5	1,001.0	8.38	3.18	11.56	2.06	0.87	2.93
Acquisitions		-		-	-	-		-	0.00
Dispositions	(1)	-	(1)	(0.67)	(0.18)	(0.85)	(0.11)	(0.03)	(0.14)
Production	(183.2)		(183.2)	(5.51)	-	(5.51)	(1.1)	-	(1.1)
Revisions	24	(124.8)	(100.8)	0.36	(1.11)	(0.75)	0.08	(0.31)	(0.23)
Total at December 31, 2004	1,844	597.5	2,441.5	43.86	10.67	54.53	9.15	2.38	11.53

GLJ used the following pricing assumptions in the escalated reserves pricing case.

Pricing assumptions	WTI	Edmonton reference price	AECO-C Spot Price
	($US/bbl)	($Cdn/bbl)	($Cdn/mmbtu)
2005	42.00	50.25	6.60
2006	40.00	47.75	6.35
2007	38.00	45.50	6.15
2008	36.00	43.25	6.00

Summary of reserve value - escalated prices

	Oil		Sales gas		NGL		Cumulative cash flow (BIT)	Discounted (per year) at:	
Reserves category	Gross	Net	Gross	Net	Gross	Net	Undisc.	10%	15%
	(mbbl)		(mmcf)		(mbbl)			($000s)	
Proved producing	4	3	37,454	28,636	1,363	966	157,571	95,382	80,907
Proved developed non-producing	54	47	2,176	1,652	120	80	12,331	8,192	7,103
Proved undeveloped	0	0	4,222	3,498	304	217	19,448	6,408	4,119
Total proved	58	50	43,852	33,786	1,787	1,263	189,350	109,982	92,129
Probable	91	72	10,685	8,141	507	346	48,224	16,483	11,822
Total proved plus probable	149	122	54,537	41,927	2,294	1,609	237,574	126,465	103,951

Gross reserves are the total of the Corporation's working and/or royalty interest share before deduction of royalties owned by others.

Net reserves are the total of the Corporation's working and/or royalty interest share after deducting the amounts attributable to royalties owned by others.

management's discussion and analysis

LAND

High Point's undeveloped land was valued at $16.0 million at December 31, 2004 by Seaton-Jordan & Associates Ltd. The Corporation's land holdings at December 31, 2004 were as follows:

	Developed		*Undeveloped*		*Total*	
(acres)	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Alberta	26,412	10,961	107,795	37,918	134,207	48,879
British Columbia	12,871	12,871	73,684	69,866	86,555	82,737
Total	39,283	23,832	181,479	107,784	220,762	131,616

In 2004, High Point acquired 24 sections of land at Peggo/Pesh in northeast British Columbia and nine and one-half sections at Ferrier, all at a 100 percent working interest. At Ricinus, High Point increased its working interest in existing lands and purchased 10 sections of exploratory land with deeper zone potential. The acquisition of these lands perpetuates High Point's three year inventory of in-house exploration and development projects.

NET ASSET VALUE

($ thousands. except as indicated)	*0%*	*5%*	*10%*
Present value of P+P reserves at discount rate shown	237,574	164,128	126,465
Value of undeveloped land	16,006	16,006	16,006
Seismic value	10,900	10,900	10,900
Stock option proceeds	8,029	8,029	8,029
Net debt	(62,004)	(62,004)	(62,004)
Net asset value	210,505	137,059	99,396
Diluted shares outstanding *(thousands)*	84,744	84,744	84,744
Net asset value per share *($)*	2.48	1.62	1.17

A Corporation's reserve life has a significant impact on net asset values. The present value of High Point's long life reserves is impacted more severely by discount rates and backwardized oil and gas prices than is the case for companies with short life reserves.

The GLJ engineering evaluation forecasts future capital of $11.7 million to develop the proved and probable reserves. This capital expenditure represents 34 percent of the forecast cash flow for proved and probable reserves in 2005. Full reinvestment of cash flow would result in a significant increase in the value of the Corporation.

CONTRACTUAL OBLIGATIONS

The Corporation has lease arrangements for office space to April 30, 2006. The future minimum lease payments total $437,989 (2005 - $328,492 and 2006 - $109,497).

OFF-BALANCE SHEET OBLIGATIONS

The Corporation has no off-balance sheet obligations.

management's discussion and analysis

CHANGES IN ACCOUNTING POLICIES

Stock-based compensation
Effective January 1, 2004, the Corporation adopted a new accounting standard on stock-based compensation as presented in the CICA Handbook section 3870. The standard requires the recognition of stock-based compensation expense for all employees and non-employees using the fair value method with recognition of compensation awards as an expense. The Corporation adopted the new accounting policy in 2004 on a retroactive basis with no restatement of prior periods. Accordingly on January 1, 2004 the accumulated deficit and share capital were increased by $955,315. The Black-Scholes option pricing model has been used to calculate the fair value of the stock options granted. For the twelve months ended December 31, 2004, the Corporation recognized a compensation expense of $604,294.

Asset retirement obligation
The Corporation adopted the new standard for asset retirement obligations, as set out in the CICA Handbook section 3110, effective January 1, 2004. The new standard requires the recognition and measurement of future liabilities related to the legal obligation to abandon and reclaim property, plant and equipment. The liability must be recorded at fair value in the period in which the asset is recorded, with a corresponding increase in the recorded amounts for oil and gas properties. The amount of the asset retirement obligation accretes over time until the obligation is settled.

Full cost accounting guideline
The Corporation adopted the new guideline for full cost accounting as laid out in Accounting Guideline 16, whereby the carrying value of oil and gas properties is limited to their estimated fair value. The fair value is calculated based on the expected future cash flows from proved and probable reserves using expected future prices and costs discounted at a risk-free rate. The adoption of this new policy at December 31, 2003 resulted in no changes to the financial statements.

CRITICAL ACCOUNTING ESTIMATES

There are a number of critical estimates underlying the accounting policies we employ in preparing the Consolidated Financial Statements.

Revenue estimates
Payment for sales in the oil and gas industry occurs up to two months after the month of production. Sales are estimated based upon information received from field offices regarding production levels and published industry pricing and transportation data.

Cost estimates
Costs for services performed but not yet billed are estimated based on original quotes and historical cost information.

Reserves
The full cost method of accounting, which is used to account for oil and gas activities, relies on estimates of proved reserves that will ultimately be recoverable from the properties. These estimates are utilized in calculating unit-of-production depletion, potential impairment of asset carrying costs and future site restoration expense. The process of estimating reserves is complex and requires significant judgement, based on available geological, geophysical, engineering and economic data.

Reserves are evaluated at year-end by an independent engineering firm and quarterly updates to those reserves, as well as new reserves from wells drilled in the current year, are estimated by Company engineers. Although we make every effort to ensure that our critical estimates are accurate, changing economic and operational conditions, as well as governmental regulations, can significantly affect those estimates, which may cause significant fluctuation in earnings and cash flows.

management's discussion and analysis

BUSINESS RISKS

High Point is engaged in the exploration, development and production of crude oil and natural gas. The oil and gas business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include competition, reservoir performance uncertainties, environmental factors, and regulatory, environment and safety concerns. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services.

High Point employs highly qualified and motivated professionals, uses sound operating and business practices, and evaluates all potential and existing wells using the latest technology. High Point complies with government regulations and has in place an up-to-date emergency response test. Environment and safety policies and standards are strictly adhered to. High Point maintains property and liability insurance coverage, as well as business interruption insurance on key properties. A commodity hedging program is in place to protect product pricing on a portion of production and ensure cash flows are available for reinvestment.

CASH FLOW SENSITIVITIES

	Cash flow	*Per share basic*
	($000s)	*($)*
Natural gas price change of $0.10/mcf	610	0.008
Natural gas production change of 1 mmcf/d	1,628	0.020
Crude oil and NGLs price change of $1.00 CDN per bbl	202	0.002
Cond/NGLs production change of 100 bbls/d	816	0.010
Interest rate change of 1% on 2005 bank debt	627	0.008
Foreign exchange rate of 1% point ($US - CDN)	575	0.007

Cash flow sensitivities are calculated as they relate to the Corporation's 2005 budgeted revenues and expenses, and outstanding shares at December 31, 2004. The Corporation's current hedging contracts have not been reflected in these sensitivities.

OUTLOOK

High Point is currently completing its first quarter drilling program, with six wells drilled at Desan, two at Ricinus and one at Ferrier. Several wells drilled in 2004 in the Ferrier area were not tied in until March, resulting in first quarter 2005 production that is expected to be relatively flat. As the Ferrier wells are tied in and the expected production from first quarter drilling comes on-stream in early April, production volumes are expected to exceed 4,000 boe per day, with average production for 2005 expected to be 30 percent higher than in 2004.

A capital budget of $50 million has been approved by the Board of Directors for 2005, which includes the winter drilling program at Desan and Ricinus, as well as another active summer drilling program of 10 to15 wells at Ferrier/Ricinus and the redrilling of the exploratory well at Kotcho. A farm-in on a deeper target at Ricinus will result in an exploratory well being drilled in April/May. As production increases in 2005, cash flow will increase to bring debt to cash flow ratios to more acceptable ranges of 1.5 times or less. Cash flows are forecast to grow to a level where cash flows can sustain the ongoing capital expenditure program looking forward to 2006 and beyond.

management's discussion and analysis

QUARTERLY REVIEW OF OPERATING AND FINANCIAL PERFORMANCE

2004	*First quarter*	*Second quarter*	*Third quarter*	*Fourth quarter*	*Total*
Average daily production					
Natural gas *(mcf/d)*	14,069	16,480	15,080	15,037	15,166
Oil and liquids *(bbls/d)*	442	449	465	566	481
Barrels equivalent *(boe/d)*	2,787	3,196	2,978	3,072	3,009
Prices					
Natural gas *($/mcf)*	6.12	6.46	5.85	6.55	6.25
Light oil *($/bbl)*	41.25	47.49	63.62	57.13	48.71
Natural gas liquids *($/bbl)*	33.45	35.21	38.12	45.40	39.28
Financial *($000s)*					
Net petroleum and natural gas sales	6,649	7,682	7,270	9,297	30,898
Cash flow from operations	4,618	5,405	5,166	6,977	22,166
Per share - basic and diluted *($)*	0.07	0.07	0.07	0.09	0.29
Net income (loss) after tax	1,321	(298)	542	1,451	3,016
Per share - basic and diluted *($)*	0.02	(0.00)	0.01	0.02	0.04
Total assets	170,868	172,963	182,925	193,363	193,363
Long term financial liabilities	0	0	0	0	0

2003 (restated)	*First quarter*	*Second quarter*	*Third quarter*	*Fourth quarter*	*Total*
Average daily production					
Natural gas *(mcf/d)*	5,669	10,006	11,225	13,533	10,133
Oil and liquids *(bbls/d)*	369	396	471	493	433
Barrels equivalent *(boe/d)*	1,314	2,063	2,341	2,749	2,121
Prices					
Natural gas *($/mcf)*	7.46	6.22	5.48	5.33	5.88
Light oil *($/bbl)*	48.57	39.96	39.73	37.12	41.12
Natural gas liquids *($/bbl)*	43.42	30.94	31.94	31.69	32.61
Financial *($000s)*					
Net petroleum and natural gas sales	3,530	4,806	5,398	5,678	19,412
Cash flow from operations	2,462	3,587	2,861	3,037	11,947
Per share - basic and diluted *($)*	0.06	0.08	0.04	0.04	0.22
Net income (loss) after tax	295	1,885	(989)	454	1,644
Per share - basic and diluted *($)*	0.01	0.04	(0.02)	0.01	0.03
Total assets	71,820	74,702	140,832	151,813	151,813
Long term financial liabilities	2,862	2,881	2,899	2,918	2,918

management's report

The accompanying financial statements and all information in the annual report are the responsibility of management. Management has prepared the financial statements in accordance with accounting principles generally accepted in Canada. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and, when necessary, management has made informed judgments and estimates in accounting for transactions that were not complete at the balance sheet date. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances as indicated in the notes to the financial statements. Financial information contained elsewhere in the annual report has been prepared and reviewed by management to ensure it is consistent with the financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are protected and financial records are properly maintained to provide reasonable assurance that financial information is relevant and reliable.

The Audit Committee is appointed by the Board of Directors, and comprises directors that are not employees of the Corporation. The Committee meets regularly with management, as well as the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is discharging its responsibilities, and to review the financial statements and the external auditors' report. The Audit Committee has approved the financial statements.

G A Yeryk

Glen A. Yeryk
President and CEO

RJ Brown

James R. Borwn
Vice President Finance andCFO

auditors' report

To the shareholders of High Point Resources Inc.

We have audited the consolidated balance sheets of High Point Resources Inc. as at December 31, 2004 and 2003 and the consolidated statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants

Calgary, Canada
March 9, 2005

consolidated balance sheets

As at December 31

($)	2004	2003 (Restated - note 2)
ASSETS *(note 6)*		
Current		
Cash and cash equivalents	-	2,148,978
Accounts receivable	**9,951,298**	7,705,266
Prepaid expenses and deposits	**678,580**	735,127
	10,629,878	10,589,371
Goodwill *(note 3)*	**14,674,423**	14,588,938
Property and equipment *(note 4)*	**168,059,132**	126,635,044
	193,363,433	151,813,353
LIABILITIES		
Current		
Bank indebtedness	**131,433**	-
Accounts payable and accrued liabilities	**22,502,551**	20,595,297
Short-term debt *(note 6)*	-	10,000,000
Bank debt *(note 6)*	**50,000,000**	20,000,000
	72,633,984	50,595,297
Convertible debentures *(note 7)*	-	2,917,967
Asset retirement obligation *(note 5)*	**1,793,436**	1,521,265
Future tax liability *(note 9)*	**30,631,057**	29,836,165
	105,058,477	84,870,694
Commitments *(notes 10 and 11)*		
SHAREHOLDERS' EQUITY		
Share capital *(note 8)*	**91,151,899**	73,185,579
Contributed surplus *(note 8 (iv))*	**1,559,609**	
Common stock conversion rights *(note 8 (i))*	-	223,993
Deficit	**(4,406,552)**	(6,466,913)
	88,304,956	66,942,659
	193,363,433	151,813,353

See accompanying notes.

Approved by the Board:

Director *Director*

consolidated statements of operations and deficit

Year ended December 31

($)	2004	2003
		(Restated - note 2)
REVENUE		
Petroleum and natural gas	**44,111,853**	28,761,159
Royalties, net of ARTC	**(10,881,856)**	(7,698,531)
Transportation expense	**(2,331,701)**	(1,650,486)
Petroleum and natural gas sales, net after royalties and transportation	**30,898,296**	19,412,142
Other income	**44,758**	124,500
	30,943,054	19,536,642
EXPENSES		
Operating	**3,961,903**	3,798,875
Asset retirement accretion *(notes 2 and 3)*	**111,949**	69,422
General and administration	**2,661,482**	2,422,049
Stock-based compensation *(notes 2 and 8 (iv))*	**604,294**	-
Depletion and depreciation	**17,324,922**	12,339,486
Interest	**1,885,310**	1,016,397
Accretion on debentures *(note 7)*	**20,508**	74,360
	26,570,368	19,720,589
EARNINGS (LOSS) BEFORE INCOME TAXES	**4,372,686**	(183,947)
PROVISION FOR (RECOVERY) OF INCOME TAXES *(note 9)*		
Current	**268,787**	351,935
Future	**1,088,223**	(2,179,983)
NET EARNINGS	**3,015,676**	1,644,101
DEFICIT, BEGINNING OF YEAR	**(6,466,913)**	(8,248,746)
Retroactive application of change in accounting policy *(note 2)*	**(955,315)**	137,732
DEFICIT, END OF YEAR	**(4,406,552)**	(6,466,913)
NET EARNINGS PER SHARE (basic and diluted) *(note 8)*	**0.04**	0.03

See accompanying notes.

consolidated statements of cash flows

Year ended December 31

($)	2004	2003
		(Restated - note 2)
Cash provided by (used in):		
OPERATING ACTIVITIES		
Net earnings	**3,015,676**	1,644,101
Add items not requiring cash:		
Depletion and depreciation	**17,324,922**	12,339,486
Future income taxes	**1,088,223**	(2,179,983)
Accretion on debentures *(note 7)*	**20,508**	74,360
Asset retirement accretion *(notes 2 and 5)*	**111,949**	69,422
Stock based compensation *(notes 2 and 8 (iv))*	**604,294**	-
CASH FLOW FROM OPERATIONS	**22,165,572**	11,947,386
Change in non-cash working capital relating to operating activities	**(2,026,759)**	(5,659,973)
	20,138,813	6,287,413
FINANCING ACTIVITIES		
Increase in bank debt	**30,000,000**	20,000,000
Issue of common shares	**14,175,521**	39,535,537
Increase (decrease) in short-term debt	**(10,000,000)**	10,000,000
Proceeds from notes receivable *(note 8 (iii))*	**335,000**	450,000
	34,510,521	69,985,537
INVESTING ACTIVITIES		
Additions to property and equipment	**(62,972,499)**	(51,517,139)
Abandonments	**(226,674)**	(512,296)
Acquisition of company *(note 3)*		(28,659,909)
Proceeds on sale of oil and gas properties *(note 4)*	**4,600,623**	3,247,929
Working capital assumed on acquisition of company *(note 3)*	**(75,723)**	(6,674,740)
Change in non-cash working capital related to investing activities	**1,744,528**	7,835,459
	(56,929,745)	(76,280,696)
INCREASE (DECREASE) IN CASH	**(2,280,411)**	(7,746)
CASH (BANK INDEBTEDNESS), BEGINNING OF YEAR	**2,148,978**	2,156,724
CASH (BANK INDEBTEDNESS), END OF YEAR	**(131,433)**	2,148,978
SUPPLEMENTARY INFORMATION		
Cash interest paid	**1,885,310**	1,016,397
Cash taxes paid	**268,787**	351,935

See accompanying notes.

notes to the consolidated financial statements

1. DESCRIPTION OF BUSINESS

High Point Resources Inc. (hereafter "High Point" or the "Corporation") is incorporated under the Business Corporations Act of Alberta and its principal business activity is petroleum and natural gas exploration development and production in western Canada. High Point is listed on the TSX Exchange under the symbol "HPR

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries.

The consolidated financial statements which have been prepared in accordance with Canadian generally accepted accounting principles, have in management's opinion been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below:

Cash and cash equivalents
Short-term investments with initial maturities less than three months are considered to be cash equivalents and are recorded at cost, which approximates fair market value.

Property and equipment
Petroleum and natural gas properties and related equipment
The Corporation follows the full-cost method of accounting whereby all costs related to the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in one Canadian cost centre. Such costs include land acquisition, drilling, equipping, geological and geophysical and overhead expenses related to exploration and development activities. These costs are depleted on the unit-of-production method using estimated gross proven petroleum and natural gas reserves as determined by independent professional engineers. Petroleum and natural gas reserves are converted to a common unit of measure on an energy equivalent basis of six mcf of gas to one barrel of oil. Costs of acquiring and evaluating unproven properties are excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the properties or impairment occurs.

Proceeds from the sale of petroleum and natural gas properties and related equipment are applied against capitalized costs, with no gain or loss recognized, unless such a sale would result in a change in the rate of depletion of 20 percent or more.

Ceiling test
Effective January 1, 2004, the Corporation adopted the new CICA accounting guideline for full cost accounting as per CICA accounting guideline 16. Under the new guideline, future net revenues from 'total proved reserves' used in the 'ceiling test' calculation are estimated using expected future product prices and costs ('escalating'), whereas prior to the adoption, constant pricing was used. Future general and administrative, and financing charges, associated with the future net revenues are no longer deducted in arriving at the 'ceiling' value. Where a ceiling test failure occurs, 'probable' reserve values may now be included in determining the impairment amount which is based on the fair value of the associated reserves.

The adoption of the new guideline has resulted in no change to net income, fixed assets or other reported amounts in the consolidated financial statements.

Office furniture, equipment and other
Office furniture, equipment and other assets are recorded at cost and depreciated on a declining balance basis at rates varying from 20 to 30 percent.

Asset retirement obligation
In 2004 the Corporation adopted the new CICA accounting standard for asset retirement obligations. The standard requires the recognition and measurement of liabilities related to the legal obligation to abandon and reclaim property, plant and equipment upon acquisition, construction, development and/or normal use of the asset. The initial liability must be measured at fair value and subsequently adjusted for the accretion of discount and changes in the fair value. The asset retirement cost is capitalized as part of property and equipment and depleted into earnings over time. The adoption of the standard has been applied retroactively with restatement of prior periods and the impact is outlined on the following page.

notes to the consolidated financial statements

Balance sheet *Increase (decrease)* *($)*	*As at December 31, 2003*
Asset retirement costs included in property and equipment	1,451,843
Accumulated amortization of costs included in property and equipment	90,480
Asset retirement obligation	1,521,265
Future site restoration and abandonment costs	(451,886)
Retained earnings (deficit)	291,984

Income statement *Increase (decrease)* *($)*	*Twelve months ended December 31, 2003*
Accretion expense	69,422
Depletion and depreciation	90,480
Provision for future site restoration and abandonment	(314,154)
Net income	154,252
Net income per share	0.003

Revenue recognition
Petroleum and natural gas sales are recognized when commodities are sold.

Transportation expenses
Transportation expenses to move gas to the inlet to the Nova pipeline system are recorded as a reduction in the sales revenue.

Joint interests
Some of the Corporation's petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Corporation's proportionate interest in such activities.

Measurement uncertainty
The amounts recorded for depletion and depreciation of property and equipment, the asset retirement obligation, and the ceiling test calculation are based on estimates of proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

Income taxes
The liability method is used in accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period in which the change occurs.

Flow-through shares
The Corporation has financed a portion of its exploration and development activities through the issuance of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits to the Corporation, the carrying value of the shares issued is reduced by the tax effect of the tax benefits renounced to subscribers when the renouncements are filed.

Financial instruments
The Corporation periodically enters into commodity price derivative instruments to reduce the Corporation's exposure to adverse fluctuations in commodity prices. No contracts are entered into for trading or speculative purposes. Gains and losses relating to commodity swaps that meet hedge criteria are recognized as part of petroleum and natural gas revenue concurrently with the hedged transaction.

notes to the consolidated financial statements

Financial instruments recognized on the balance sheet include cash and cash equivalents, accounts receivable, bank indebtedness, accounts payable, short-term debt, bank debt and convertible debentures. As at December 31, 2004 and 2003 there are no significant differences between the carrying amounts reported on the balance sheet and their estimated fair values.

Stock-based compensation

Effective January 1, 2004, the Corporation adopted the new CICA accounting standard for stock based compensation. The standard requires the recognition of stock based compensation expense for all employees and non-employees using the fair value method with recognition of compensation awards as an expense. The Corporation adopted the new accounting policy in 2004 on a retroactive basis with no restatement of prior periods. Accordingly on January 1, 2004 the accumulated deficit and share capital were increased by $955,315 to reflect the cumulative effect of the change on prior periods. The Black-Scholes option pricing model has been used to calculate the fair value of the stock options granted.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is not amortized and is assessed by the Corporation for impairment at least annually. Impairment is assessed based on a comparison of fair value of the net assets acquired to the carrying value of the net assets, including goodwill. Any excess of carrying value over and above fair value is the impairment amount, and is charged to earnings in the period identified.

3. ACQUISITION OF GLACIER RIDGE RESOURCES LTD.

On July 15, 2003, the Corporation acquired all of the issued and outstanding shares of Glacier Ridge Resources Ltd. ("Glacier"). The Glacier acquisition was accounted for by the purchase method and shares were acquired for an aggregate of:

a. $28.5 million in cash and transaction costs of $159,909;
b. $10.5 million payable by the issuance of 6,562,504 common shares of High Point at a deemed value of $1.70 per common share; and
c. non-interest bearing promissory notes due August 31, 2004 in an aggregate amount equal to a portion of the difference in reserve value of Glacier's properties on July 1, 2004 compared with April 1, 2003, and which was not to exceed $4.2 million. On the date of acquisition, no value was assigned to the notes as the amount could not be quantified. Glacier's bank debt and working capital deficit, totaling approximately $6.79 million, were assumed in the acquisition. At August 31, 2004 the promissory notes expired with no additional reserve value attributed to the Glacier properties during the agreement period ended July 1, 2004.

In 2004, the Corporation increased goodwill by $85,485 to reflect an increase in Glacier Ridge's pre acquisition working capital deficit and an adjustment to the carrying value of property, plant and equipment.

	($)
Calculation of purchase price:	
Fair value of cash and shares issued	39,656,257
Transaction costs	159,909
	39,816,166
Allocation of purchase price:	
Goodwill	14,674,423
Property, plant and equipment	43,605,213
Working capital deficit and debt	(6,750,463)
Future site restoration	(59,199)
Future income tax	(11,653,808)
	39,816,166

notes to the consolidated financial statements

4. PROPERTY AND EQUIPMENT

	2004		
($)	Historical cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties and related equipment	217,880,920	50,048,221	167,832,699
Office furniture, equipment and other	576,429	349,996	226,433
	218,457,349	50,398,217	168,059,132

	2003		
($)	Historical cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties and related equipment	159,229,615	32,782,610	126,447,005
Office furniture, equipment and other	576,576	388,537	188,039
	159,806,191	33,171,147	126,635,044

On January 28, 2004, the Corporation sold its interest at Wembley, Alberta, for net proceeds of $1,086,623, and on November 1, 2004, the Corporation sold its interest at Alexander/Newton, Alberta, for proceeds of $3,514,000. No gain or loss was recognized on these disposals.

On December 1, 2003, the Corporation sold its interest at Progress and Monitor Alberta, as well as its heavy oil properties at Lloydminster, Saskatchewan for net proceeds of $2,535,948. In addition, various other minor interests were sold for proceeds of $711,981 in 2003.

During 2004, $258,741 of general and administrative expenses were capitalized (nil in 2003).

At December 31, 2004, carrying costs of $13,500,891 (2003 - $8,050,497) related to unproven properties have been excluded from the depletion calculation.

At December 31, 2004, property, plant and equipment includes costs of $1,571,759 related to the asset retirement obligation (net of depletion). Actual abandonment costs for 2004 were $226,674 (2003 - $512,296).

5. ASSET RETIREMENT OBLIGATION

The Corporation's asset retirement obligations result from net ownership interests in oil and gas assets. The total estimated undiscounted cash flows required to settle these asset retirement obligations is approximately $3.8 million which will be incurred between 2004 and 2024. A credit adjusted risk free rate of 4.5 percent and an inflation rate of 2.1 percent were used to calculate the fair value of the obligation.

	Years ended December 31	
Asset retirement obligation	2004	2003
Balance - beginning of year	**1,521,265**	867,781
Liabilities incurred	**386,896**	1,096,358
Accretion expense	**111,949**	69,422
Liabilities settled	**(226,674)**	(512,296)
Balance - end of year	**1,793,436**	1,521,265

notes to the consolidated financial statements

6. LOANS

At December 31, 2004, the Corporation has a revolving term credit facility with a Canadian chartered bank. The facility consists of two parts, Part A is for $54,000,000 with interest at the bank's prime rate plus 0.25 percent, and Part B is for an additional $6,000,000 with interest at the bank's prime rate plus 1.25 percent. Collateral for the facility consists of a demand debenture for $100,000,000 secured by a first floating charge over all assets. At December 31, 2004, $50,000,000 was drawn against the credit facility. The Corporation had additional financing by way of a 'Secured Development Bridge Facility' set up with a Canadian lending corporation. This facility provided $10,000,000 on November 17, 2003 with an additional $5,000,000 drawn on January 28, 2004. The effective interest rate was at bank prime plus three percent and the maturity date was January 1, 2005. In addition, the lender was granted a five percent gross overriding royalty ('GOR') on selected future development projects, reducing to a 1.6 percent GOR upon prepayment of the loan. On July 21, 2004, the Corporation repaid the $15,000,000 'Secured Development Bridge Facility'. In doing so, the Gross Overriding Royalty which was placed on specific development projects during the loan period, was fixed at 1.6 percent. On December 2, 2004 a standby 'Secured Development Bridge Facility' was set up with a Canadian lending corporation. The facility would allow for up to two drawdowns before March 31, 2005 for a minimum of $7,500,000 on the first drawdown, and to a maximum of $15,000,000 combined. Interest would be paid at bank prime plus 3.25 percent. As of December 31, 2004, the facility has not been activated and no amount has been drawn against it.

On March 4, 2005, the first drawdown of $7,500,000 on the bridge facility occurred, with a second draw planned before the end of March, 2005. For the year ended December 31, 2004, the effective interest rate on all borrowings was 4.4 percent (4.7 percent in 2003).

7. CONVERTIBLE DEBENTURES

The Corporation had convertible debentures outstanding of $3,000,000 at December 31, 2003. Pursuant to the terms of the debentures the holders exercised their right to convert the debentures into common shares at $1.60 per share prior to March 31, 2004 (see note 8(i)). Interest on the debentures was payable quarterly at an annual rate of seven percent. For the first quarter of 2004, the Corporation incurred interest expense of $48,818 on the debentures plus non-cash financing charges of $20,508 related to the accretion of the discount on the debentures.

8. SHARE CAPITAL

Authorized
Unlimited number of voting common shares with no par value.
Unlimited number of non-voting preferred shares issuable in series.

Issued and outstanding common shares

	Number of Shares	*Amount ($)*
Balance at December 31, 2002	39,366,150	31,626,326
Issue of common shares for cash *(ii)*	7,634,207	11,069,600
Issue on acquisition of Glacier *(v)*	15,937,504	26,156,257
Issued for cash on exercise of stock options	331,667	208,500
Issue of flow-through common shares for cash *(ii)*	7,200,000	16,000,000
Share issue costs, net of tax of $1,117,595		(1,624,969)
Tax benefits renounced on flow-through shares *(ii)*		(10,700,135)
Repayment of notes receivable *(iii)*		450,000
Balance at December 31, 2003	70,469,528	73,185,579
Conversion of debentures *(i)*	1,875,000	3,162,468
Issued for cash on exercise of stock options	171,668	151,511
Share issue costs, net of tax of $343,761		(678,729)
Repayment of notes receivable *(iii)*		335,000
Issue of common shares for cash *(ii)*	3,870,000	7,546,500
Issue of flow-through common shares for cash *(ii)*	3,000,000	7,500,000
Tax benefits renounced on flow-through shares *(ii)*		(50,430)
Balance at December 31, 2004	79,386,196	91,151,899

notes to the consolidated financial statements

(i) As described in Note 7, the convertible debentures were converted to shares in the first quarter 2004. 1,875,000 shares at $1.60 per share were issued in exchange for retirement of the debenture liability. The carrying value of the debentures prior to conversion was $2,938,475. In addition, the $223,993 equity component representing the holders' conversion rights based upon fair value of the debentures at the time of issue, was applied to share capital.

(ii) In May 2004, the Corporation issued 3,870,000 common shares at $1.95 per share for proceeds of $7,546,500 and 3,000,000 flow-through shares at $2.50 per share for proceeds of $7,500,000. The Corporation renounced $150,000 to the shareholders at June 30, 2004 and the balance in January, 2005, having expended $6,300,000 in exploratory costs relating to this issue in 2004, and under the 'look back' provision governing flow-through shares, will be required to expend the balance of $1,200,000 prior to December 31, 2005. The aggregate tax benefit lost by the Corporation is $2,521,500 at current tax rates.

On October 31, 2002, the Corporation issued 8,548,332 flow-through shares for proceeds of $10,258,001 less issue costs of $694,260. The Corporation renounced $10,258,001 to shareholders in 2002 and expended the full amount in 2003. The taxable benefit lost to the Corporation in 2003 was $4,180,135. On March 12, 2003, the Corporation issued 7,634,207 common shares at $1.45 per share for proceeds of $11,069,600 less issue costs of $749,200.

On June 24, 2003, the Corporation issued 4,000,000 flow-through shares at $2.00 per share for proceeds of $8,000,000 less issue costs of $497,500.

On December 23, 2003, the Corporation issued 3,200,000 flow-through shares at $2.50 per share for proceeds of $8,000,000 less issue costs of $497,500.

At December 31, 2004 all of the $16,000,000 in exploratory costs required to be expended under the 2003 flow-through share offerings had been incurred. These costs were renounced to shareholders in 2003. The tax benefit lost to the Corporation in 2003 was $6,520,000.

(iii) Interest free loans were issued by the Corporation in 2001 and 2002 to certain officers and an employee for the purpose of purchasing shares of the Corporation. The loans are evidenced by promissory notes and the shares are pledged to the Corporation as collateral. The shares are being held in trust, to be released as the loans are repaid. During 2004 $335,000 of such loans were repaid (2003 - $450,000) and at December 31, 2004, $555,000 remains outstanding. The market value of the shares held as collateral at December 31, 2004 was $805,329.

(iv) As described in note 1, the Corporation adopted a new accounting policy with respect to stock-based compensation in 2004. The effect on contributed surplus at January 1, 2004 for retroactively adopting the standard without restatement of prior periods was $955,315. The stock-based compensation expense for 2004 was $604,294 and was applied to contributed surplus.

(v) On July 15, 2003, the Corporation issued 9,375,000 common shares at $1.60 per share for proceeds of $15,000,000, which proceeds were used in the acquisition of Glacier. A further 6,562,504 common shares were issued at a deemed value of $1.70 per share as part of the consideration paid for the acquisition of Glacier. Share issue costs of $998,364 were incurred in relation to this issue.

Stock options

The Corporation has established a stock option plan whereby options may be granted to the Corporation's directors, officers and employees for up to 10 percent of the common shares issued and outstanding. The exercise price of each option equals the market price of the Corporation's stock on the date of the grant and an option's maximum term is five years. The stock options vest one-third immediately, one-third after one year following the date of grant and one-third two years following the date of grant. A compensation expense of $604,294 was recognized in 2004 under the plan. The table on the following page is a continuity of stock options outstanding for which shares have been reserved.

notes to the consolidated financial statements

	2004		2003	
	Number of shares	Weighted average exercise price	Number of shares	Weighted average exercise price
		($)		($)
Opening	**3,350,002**	**1.25**	2,696,669	1.05
Granted	**2,215,000**	**1.84**	985,000	1.60
Exercised	**(171,668)**	**0.88**	(331,667)	0.63
Expired	**(36,000)**	**2.35**	-	-
Closing	**5,357,334**	**1.50**	3,350,002	1.25
Exercisable, end of year	**3,576,196**	**1.35**	2,151,528	1.16

	Options outstanding			Options exercisable	
Range of exercise prices	Number outstanding	Weighted average remaining life	Weighted average exercise price	Number exercisable	Weighted average exercise price
		(years)	($)		($)
$0.30 - $0.69	150,001	1.5	0.39	150,001	0.39
$0.90 - $1.05	241,667	0.7	1.00	241,667	1.00
$1.20 - $1.20	1,801,666	2.4	1.20	1,801,666	1.20
$1.58 - $1.80	2,708,000	4.2	1.74	1,230,877	1.66
$2.06 - $2.35	456,000	4.2	2.19	151,985	2.19
	5,357,334	3.4		3,576,196	1.35

The fair value of options granted during the year was estimated at the date of grant using a Black-Scholes Option Pricing Model with the following assumptions for 2004: risk-free interest rate of 3.5 to 3.9 percent; dividend yield of zero percent; volatility factor of the market price of the Corporation's common shares of 36 to 40 percent; and, an average expected life of the options of three years. For purposes of pro-forma disclosure, the estimated fair value of the options is amortized to expense over the option vesting periods. On a pro-forma basis, had the fair value method been used in 2003, the net loss for the year ended December 31, 2003 would be increased by $81,894. Basic and diluted net loss per share would be unchanged.

Earnings per share

The Corporation utilizes the treasury stock method in the determination of diluted per share amounts. Under this method, the diluted weighted average number of shares is calculated assuming the proceeds that arise from the exercise of outstanding and in the money options are used to purchase common shares of the Corporation at their average market price for the period. The weighted average number of common shares outstanding during the year was 75,766,587 (2003 - 55,329,790) and 77,130,290 diluted (2003 - 56,246,310).

9. FUTURE INCOME TAXES

The components of the future income tax liability are as follows:

	2004	2003
($)		
Differences between tax base and reported amounts for depreciable assets	**26,356,290**	35,328,662
Benefit of non-capital losses	**(2,173,703)**	(2,983,032)
Benefit of attributed crown royalty income	**(823,573)**	(596,582)
Share issue costs		(1,586,944)
Provision for future site restoration and abandonment costs		(325,939)
Partnership deferral	**7,272,043**	
	30,631,057	29,836,165

notes to the consolidated financial statements

The total income taxes are different than the amount computed by applying the combined Canadian federal and provincial corporate tax rates of 38.87 percent (2003 - 40.75 percent) to the earnings (loss) before taxes. The majority of these differences are explained as follows:

($)	2004	2003
Expected tax	**1,707,971**	(137,816)
Add (deduct) income tax effect of:		
Non-deductible crown royalties, net of ARTC	**2,372,622**	2,042,346
Resource allowance	**(1,784,332)**	(1,510,154)
Attributed Royalty Income Carry forward	**(153,734)**	(99,052)
Share Issue costs		
Income tax rate reduction	**(1,007,349)**	(2,462,910)
Non-taxable or non-deductible items	**247,686**	(58,020)
Part XII.6 tax	**162,016**	63,893
Large corporation tax	**106,771**	288,043
Other	**(294,641)**	45,622
Income taxes (recovery)	**1,357,010**	(1,828,048)

10. COMMITMENTS

The Corporation has entered into lease arrangements for office space to April 30, 2006. The future minimum lease payments total $465,527 (2005 - $328,607 and 2006 - $136,920).

11. FINANCIAL INSTRUMENTS

Gas hedging

Period	*Volume hedged*	*AECO price*
Nov. 1, 2004 - Mar. 31, 2005	3,000 GJ/day (2.9 mmcf/d)	$7.90/GJ ($8.32/mcf)
Nov. 1, 2004 - Mar. 31, 2005	3,000 GJ/day (2.9 mmcf/d)	$8.01/GJ ($8.41/mcf)
Nov. 1, 2004 - Mar. 31, 2005	2,000 GJ/day (1.9 mmcf/d)	$8.58/GJ ($9.01/mcf)
Apr. 1, 2005 - Oct. 31, 2005	6,000 GJ/day (5.7 mmcf/d)	$6.95/GJ ($7.30/mcf)

The estimated fair value of the Corporation's commodity hedging contracts at December 31, 2004 was $958,980, being the amount the Corporation would gain if it sold off its position.

12. SUBSEQUENT EVENTS

Effective January 1, 2005, the Corporation purchased the rights to the Gross Overriding Royalty for the Desan area of northeast British Columbia for $590,000. The Gross Overriding Royalty had been part of the Bridge Financing Facility set up in 2003, as described under note 6.

An agreement is in place whereby the Corporation's interests at Medicine Lodge will be sold effective March 31, 2005 for proceeds of $2.6 million.

On February 24, 2005, the Corporation entered into a natural gas swap and matching physical sale with a major Canadian marketer, fixing the price on 3,000 GJ per day of natural gas at $6.82 per GJ for the period April 1, 2005 through October 31, 2005.

corporate information

BOARD OF DIRECTORS

John A. Brussa [2]
Glenn R. Carley [1,2]
Fred C. Coles [1]
Gary K. Bauer
Christina M. Fehr [2]
Donald Rowden [1]
Glen A. Yeryk

[1] *Audit and Reserves Committee*
[2] *Compensation Committee*

EXECUTIVE OFFICERS

Glen A. Yeryk, *President & CEO*
Mark Armanious, *VP Exploration*
Jim Brown, *VP Finance & CFO*
Neil McPherson, *VP Land*
Dennis Miller, *VP Production & Operations*
Stewart Larsen, *Controller*

REGISTRAR AND TRANSFER AGENT

Valiant Trust Company
Calgary, Alberta

AUDITORS

Ernst & Young LLP
Calgary, Alberta

EVALUATION ENGINEERS

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading Symbol "HPR"

CORPORATE OFFICE

1400, 255 - 5th Avenue SW
Calgary, Alberta T2P 3G6
Telephone: (403) 264-2487
Fax: (403) 264-2498
www.highpointres.com

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

WTI	West Texas Intermediate
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bbl	Barrel
Bbls	Barrels
Mbbls	Thousand barrels
MMbbls	Million barrels
Bbls/d	Barrels per day
BOE	Barrels of oil equivalent
MBOE	Thousands of barrels of oil equivalent
MMBOE	Millions of barrels of oil equivalent
BOE/d	Barrels of oil equivalent per day
NGL	Natural gas liquid
STB	Stock tank barrel
MSTB	Thousand stock tank barrels
MMSTB	Million stock tank barrels

Natural Gas

Mcf	Thousand cubic feet
Mmcf	Million cubic feet
Bcf	Billion cubic feet
Mcf/d	Thousand cubic feet per day
Mmcf/d	Million cubic feet per day
GJ	Gigajoule
MMBTU	Million British thermal units
MM	Million

CONVERSION

To convert from	*To*	*Multiply by*
BOE	Mcf	6
Mcf	Cubic metres ("m3")	28.174
Bbls	Cubic metres ("m3")	0.159
Feet	Metres	0.305
Miles	Kilometres	1.609
Acres	Hectares	0.400
Hectares	Acres	2.500

Designed by Sandy Seifert Printed by Signature Press Inc.

HIGH POINT
RESOURCES INC.

www.highpointres.com